Decision 04-06-013 June 9, 2004

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation into Implementation of Assembly Bill 970 Regarding the Identification of Electric Transmission and Distribution Constraints, Actions to Resolve Those Constraints, and Related Matters Affecting the Reliability of Electric Supply.	Investigation 00-11-001 (Filed November 2, 2000)

INTERIM OPINION ADOPTING METHODOLOGY FOR CONSIDERATION OF TRANSMISSION COSTS IN RPS PROCUREMENT

Table of Contents

Title **Page**

Table of Contents

INTERIM OPINION ADOPTING METHODOLOGY FOR CONSIDERATION OF TRANSMISSION COSTS IN RPS PROCUREMENT

I. Summary

This decision adopts guidelines for the development and use of transmission costs in assessing Renewable Portfolio Standard (RPS) bids in the initial RPS procurement to be undertaken pursuant to Pub. Util. Code § 399.14.[1] This initial procurement, to begin by July 1st of this year, represents the first step in a multi-year effort under the RPS program to substantially alter the electric generation resource mix in California, with the goal of achieving a resource portfolio that is at least 20% renewable. The Commission is strongly committed to achieving this goal - more quickly, in fact, than is required by the RPS statute, as expressed in the Joint Agency Energy Action Plan.[2] These guidelines will facilitate the first RPS solicitation.

Forward-looking transmission policies are key to the success of the RPS program. Critical issues such as the planning process for large-scale transmission upgrades needed to transport power from areas with significant renewable resource potential, funding policies for new transmission facilities that are necessary to facilitate achievement of the renewable power goals, and assessment of economic benefits that may accrue from transmission upgrades are under consideration in other phases of this proceeding. We expect that those efforts, along with the valuable experience to be gained through this initial RPS

---

1 All statutory references are to the Public Utilities Code.

2 http://www.cpuc.ca.gov/static/industry/electric/energy+action+plan/index.htm.

procurement, will allow us to refine the methodology adopted today for use in consideration of transmission costs in subsequent RPS procurements.

In today's order, we require that Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) each prepare and file a Transmission Ranking Cost Report prior to the initial RPS procurement solicitation. In its Transmission Ranking Cost Report, each utility should identify and provide cost information regarding transmission upgrades needed for potential RPS projects, based on conceptual transmission studies submitted previously in this proceeding, other conceptual transmission studies, and System Impact Studies and Facilities Studies prepared for projects that have initiated the California Independent System Operator (ISO) interconnection process. Potential RPS bidders should use the information regarding expected transmission upgrades in developing their bids in response to the initial RPS procurement solicitation.

The utilities should also use the transmission cost estimates in the Transmission Ranking Cost Reports in evaluating RPS bids. We adopt guidelines for the utilities' use of the identified transmission costs in ranking the bids, including the calculation of transmission cost bid adders and the assignment of these adders to specific RPS projects. Each utility should use the adopted iterative method in determining the combination of projects that will meet its approved renewable procurement goals in a least-cost, best-fit manner.

It is important to note that the estimates of transmission costs in the Transmission Ranking Cost Reports will not be definitive and will not establish the ultimate cost of connecting a renewable resource to the grid. Renewable projects that have not already done so will need utilize the ISO System Integration Study and Facility Study process to determine these costs. The reported estimates will be used solely to evaluate bids one against another, and may prove to be quite rough estimates of actual transmission upgrade costs. If the methodology adopted today is applied uniformly, however, renewable bidders should not be disadvantaged by this approximation and the utilities can make an informed judgment as to the relative merits of RPS bids.

II. Procedural Background

In Decision (D.) 03-06-071 in Rulemaking (R.) 01-10-024, the Commission took the first steps to implement the RPS program adopted in Senate Bill (SB) 1078. We adopted, among other things, a process for the rank ordering and selection of least-cost and best-fit renewable resources to comply with the statutory annual obligations of the RPS program. The adopted ranking process is iterative. In the first step, bids are to be ranked according to a product-specific market price referent. In the second ranking, bids are to be re-ordered based on integration and transmission costs. In D.03-06-071, we determined that a PG&E proposal submitted in that proceeding was a reasonable starting point as a methodology for consideration of transmission costs in the second ranking of RPS bids, and deferred refinement of the approach to this proceeding.

On March 5, 2004, a prehearing conference (PHC) was held in this proceeding regarding establishment of the methodology for consideration of transmission costs for RPS purposes, consistent with D.03-06-071. In preparation for the PHC, PG&E filed and served on all parties its proposal for the treatment of transmission costs, as submitted in R.01-10-024 and referenced in D.03-06-071. PG&E, SCE, SDG&E, the Center for Energy Efficiency and Renewable Technologies (CEERT), and the California Wind Energy Association (CalWEA) filed PHC statements in advance of the PHC. The assigned administrative law judge (ALJ) allowed Vulcan Power Company to late-file its PHC statement.

During the PHC, there was general agreement among the parties that the Commission should adopt an interim methodology for the development and consideration of transmission costs for use during the initial RPS procurement. Various issues of concern related to consideration of transmission costs were discussed. The parties disagreed to some extent regarding which transmission-related issues should be addressed before the initial RPS procurement and which should be deferred until a later time. However, there was general agreement that, in order to allow the initial procurement to proceed on a timely schedule, transmission costs to be used in assessing renewable projects that do not have completed System Integration Studies and Facility Studies should be based on existing conceptual transmission studies.

The utilities have undertaken conceptual transmission studies based on prior solicitations of interest to potential renewable developers. On March 19, 2004, consistent with determinations at the PHC, the assigned ALJ issued a ruling directing that by April 2, 2004 PG&E, SCE, and SDG&E request any further information needed from potential renewable energy bidders so that they could prepare additional conceptual transmission studies, if needed to develop transmission cost estimates for the initial RPS procurement.

As another step established at the PHC, the ALJ issued an additional ruling on April 2, 2004 (hereinafter referred to as the ALJ ruling), which contained proposed guidelines for the development and consideration of transmission costs during the initial RPS procurement. The proposal was based on PG&E's original proposal in R.01-10-024 and on PHC statements and discussions. PG&E, SCE, SDG&E, The Utility Reform Network (TURN), CEERT, and CalWEA filed comments and reply comments on the interim methodology proposed in the ALJ ruling.

III. Interim Methodology for Identification and Consideration of Transmission Costs

In this section, we discuss contested issues regarding development and consideration of transmission costs during the initial RPS procurement. Attachment A contains the comprehensive Interim Methodology that we adopt for this purpose.

A. Reliance on Existing Transmission Studies

The ALJ ruling proposed that, for interim purposes, the utilities prepare transmission cost estimates based on their most recent conceptual transmission studies, including the studies prepared for SB 1038 compliance and submitted on August 31, 2003 in this proceeding, conceptual transmission studies prepared in response to the March 19, 2004 ALJ ruling, and other comparable studies. The utilities would also rely on any System Impact Studies and Facilities Studies they may have for projects that have initiated the interconnection process and are in the ISO interconnection queue. Cost estimates in existing studies would be adjusted if needed to reflect that construction may occur in a different year than assumed in the study.

In their comments, no party took issue with the proposal that existing conceptual transmission studies be used in evaluating bids received in response to the initial RPS procurement solicitation. While CEERT supports the use of existing studies, it recommends that each utility's Transmission Ranking Cost Report be reviewed to permit adjustments for any inappropriate assumptions. CEERT asserts that, for some transmission upgrades purported to be needed for RPS procurement, it is impossible to distinguish between their use for RPS-related energy and their use for other potential energy flows.

PG&E responds that questioning the utility's assignment of transmission upgrade costs should not be allowed because this would not add any value and would only serve to slow down the RPS solicitation process. PG&E maintains that its Transmission Ranking Cost Report will rely on base cases that include all reliability-driven and economic transmission projects and that none of the costs for such projects would be attributed to RPS projects. PG&E asserts that the ISO's interconnection process is the appropriate forum for a renewables developer to dispute the attribution of a transmission upgrade to its project.

We find that it is reasonable for the utilities to prepare transmission cost estimates for use in evaluating bids received in response to the initial RPS solicitation using the most recent conceptual transmission studies, to the extent that System Impact Studies and Facilities Studies do not exist or are not sufficient. As ordered in D.03-06-071 and consistent with CEERT's recommendation, the parties should be allowed to review the Transmission Ranking Cost Reports and challenge their assumptions and results. In Section III.N, we establish the manner whereby parties may comment on the Transmission Ranking Cost Reports and on their use in the evaluation of RPS bids.

B. Treatment of Shared Transmission Facilities

It may be difficult for individual developers to identify the extent to which they could reduce their costs and increase the competitiveness of their projects through sharing gen-tie facilities with other nearby projects. In addition, the proper demarcation between gen-ties and network transmission facilities may not always be clear.

To assist identification of the most cost-effective renewable projects in light of these difficulties, the ALJ ruling proposed that the utilities treat all transmission upgrades identified in their conceptual studies that would carry power from more than one renewable project as network transmission facilities, regardless of whether the utilities consider such facilities to be gen-ties or network transmission facilities. The cost of all such shared facilities would be included in the transmission cost adders rather than in projects' RPS bids. The shared facilities, like other transmission facilities, would be assigned to individual RPS projects in a manner that would allow the least-cost selection of winning bids. The ALJ ruling emphasized that the proposed approach would not prejudge the ultimate classification of the shared transmission facilities as either gen-ties or network transmission facilities.

1. Positions of the Parties

In comments, SCE and PG&E take issue with this aspect of the ALJ ruling. PG&E maintains that the costs of all gen-tie facilities should be reflected in the price of power bid by the developers, citing the statements in D.03-06-071 that the cost of Direct Assignment facilities should be included in the bid and that interconnection facilities will be included in the Market Price Referent and therefore need to be included by the developers in their bids. PG&E argues that transmission costs should be classified consistently as either direct costs (to be internalized in the bid) or indirect costs (to be used in the second bid ranking process). PG&E explains that the methodology in the ALJ ruling for handling these costs could result in the submission of bids that do not reflect the total direct costs that renewables generators may be required to bear should they become winning bidders. As a result, the bid prices could later turn out to be insufficient to cover the developers' costs.

PG&E argues that only Federal Energy Regulatory Commission (FERC) can determine the classification of transmission facilities needed for RPS projects.

PG&E maintains that under FERC precedent the dividing line between gen-ties and network facilities is the point at which new generation is first interconnected to the existing transmission system, and that the number of generation facilities using the gen-ties is not relevant to their classification under federal law. SCE and PG&E also point out that the Commission has argued before FERC that network transmission lines used primarily by multiple generators should be classified as gen-ties.

PG&E and SCE assert that exclusion of gen-tie facilities from the developers' bids could lead to inaccurate bid ranking results. They argue that this approach would lead to inequitable treatment of, e.g., a lone RPS generator located at the end of a gen-tie line compared to two RPS generators located near each other that would both use a single line, and would inaccurately reflect the true cost to ratepayers. PG&E submits further that treating the cost of shared gen-tie facilities as an indirect cost to be added to bids would send a potentially inaccurate signal to developers and would tend to encourage developers to site their facilities in other areas for which the Transmission Ranking Cost Report lists lower indirect transmission costs.

PG&E also submits that the utilities are in no position to estimate the cost of gen-tie facilities and that developers are better able to estimate the costs of facilities needed between their planned development and the first point of interconnection to the existing grid.

CEERT supports the treatment of shared gen-tie and network upgrades proposed in the ALJ ruling. CEERT submits that inclusion of shared interconnection facilities in the bid adder rather than in individual generators' bids is the only logical way to ensure that these facilities will be counted only once. CEERT maintains that, if such facilities were included in individual bids, generators would need prior knowledge of each other's bids in order to cooperatively design common facilities. Otherwise, the bids would include duplicative feeder lines, each spanning the entire distance to the existing grid. CEERT asserts that the purpose of the proposed methodology is only to evaluate bids, not to conduct precise engineering studies to construct actual facilities or to assign detailed cost allocation/financing responsibility for the transmission upgrades. CEERT maintains that these latter functions belong at the end of the process, not at the beginning.

CalWEA takes issue with PG&E's position that all facilities located before the point of interconnection to the existing transmission grid would be gen-ties. CalWEA points out that a network upgrade can expand the boundaries of the transmission grid, contrary to PG&E's implicit position that the boundaries of the transmission grid, once installed, never change.

2. Discussion

On balance, we conclude that the method in the ALJ ruling for the treatment of shared transmission upgrades in assessing RPS bids should be modified. Contrary to PG&E's claims, whether shared gen-tie facilities are included in the developers' bids or in the transmission adder should not affect the ultimate least-cost, best-fit results. Thus, inclusion of such costs in the second ranking would not treat isolated generators inequitably or modify incentives for project location. However, we agree with PG&E that this approach may not lead to viable contracts with prices adequate to cover the developer's costs in instances where the shared network facilities are ultimately deemed to be gen-ties to be constructed by the developer.

At the same time, we are concerned that a procurement process that does not take into account that gen-ties may be shared by multiple projects would not reveal the least-cost renewable generation options. We therefore adopt the following steps to allow proposals for shared gen-ties to be considered in the bid evaluation and negotiation process between the utilities and renewable developers.

Each utility should describe in its Transmission Ranking Cost Report any transmission facilities identified in its conceptual studies that may be shared by more than one renewable project, but which the utility considers to be gen-ties rather than network facilities. The utility should specify both the location and capital costs of such facilities, and explain why it believes the facilities should be classified as gen-ties rather than network facilities. The developers may use this information in constructing their bids and may also contest the utility's determination through comments on the Transmission Ranking Cost Reports, as provided elsewhere in this decision.

To allow for the potential sharing of gen-tie costs, each bidder may choose to list its estimated gen-tie costs independently, and the utility will make iterative adjustments to its bid ranking to account for sharing of these costs among those bidders who are selected. While we recognize the extra analytic burden this requirement places on the utilities, they are directed to make their best efforts to find such cost-sharing opportunities, which, to the extent they can be captured, will result in lower costs to ratepayers. The utilities should present the results of this analysis to their Procurement Review Groups for review.

The adopted approach, in which the utility evaluates the possibility of shared gen-tie expenses for multiple bidders, is workable for the initial RPS solicitation but is not ideal. In another phase of this proceeding, we are considering whether current transmission planning procedures should be modified in areas where generation from multiple projects may be transported most economically over shared transmission facilities. The pending Proposed Decision in the Tehachapi phase of this proceeding would require a comprehensive transmission expansion plan for the Tehachapi area. If adopted, the collaborative study group created to develop this plan would also address whether this transmission planning approach should apply in other areas of the state with renewable resources. Such an effort would improve the identification of transmission facilities that may be shared among renewable projects and may lead to refinements in our future evaluations of annual RPS solicitations, hopefully starting in 2005.

We agree with CalWEA that, even under the utilities' view of the gen-tie/network facilities demarcation, network transmission upgrades may expand the grid and add new points of interconnection. If a utility includes any network upgrades in its Transmission Ranking Cost Report that would expand its grid and add new substations and thus new points of interconnection, the utility should specify the expected location of each new substation, so that project developers may assess their expected costs if they plan to interconnect at that substation. To the extent consistent with existing conceptual studies, the utilities should identify substation locations based on knowledge regarding both currently proposed and potential future renewable projects.

C. Network Benefits

The ALJ ruling would reject both CalWEA's request that the Commission make a blanket determination that network benefits of transmission upgrades exceed their costs and, as a result, that no transmission costs be included in the assessment of RPS bids, and CalWEA's alternative request that hearings be held at this time to identify network benefits as offsets to transmission upgrade costs attributed to renewable projects. The ALJ ruling noted that, as provided by

D.03-06-071, bidders may describe in their bids potential network benefits of their renewable projects, along with their projects' expected effects on local reliability, low income or minority communities, environmental stewardship, and resource diversity, for the soliciting utility's consideration in evaluating the bid. Other than mandating consistency and transparency, the ALJ ruling did not specify the manner in which a utility should consider such factors in assessing project bids.

1. Positions of the Parties

In its comments on the ALJ ruling, CalWEA reiterates its position that transmission costs should be assessed to RPS bids net of identified benefits. It maintains that transmission bid adders that disregard network benefits would conflict with the statutory requirement that least-cost, best-fit resources be chosen on a total cost basis. Based on its view that most upgrades operating at voltages of 230 kilovolts (kV) and above will benefit the network, CalWEA suggests a rebuttable presumption that the net cost of transmission adders for such upgrades would be zero. For lower voltage upgrades, CalWEA recommends that the transmission owner be required to estimate savings due to lower line losses and also be required to estimate the increase in transfer capability across existing constrained interfaces. CalWEA maintains that, as the ISO implements Market Design 2002, it will be able to quantify the value of increased transfer capability based on locational marginal prices at each node of the ISO transmission system. CalWEA suggests that network benefits can be established through witness affidavits without the need for evidentiary hearings.

PG&E and SCE take issue with CalWEA's interpretation that the statute requires consideration of net transmission costs, since the statute does not mention, much less require, the use of network benefits to offset transmission costs. To the contrary, they oppose any consideration of network benefits in the rank ordering of RPS bids. PG&E and SCE maintain that, since reliability and economic transmission upgrades are already included in the utilities' grid expansion plans and in the base cases used for the conceptual studies, it follows that all of the costs of transmission projects triggered by winning RPS bids are due to the RPS projects and must be accounted for in evaluating the overall cost of the competing bids.

PG&E and SDG&E assert that an attempt to quantify purported network benefits would take much longer than CalWEA assumes and would require much more detailed information than is currently available. They explain that the existing conceptual studies are based on proxy facilities, simplified input from the potential resource developers, and simplified solution techniques. SDG&E and TURN note that CalWEA's suggestion to use locational marginal prices to value transmission upgrades is not possible until the ISO's Market Design 2002 is implemented. PG&E maintains that the economic benefits, if any, of network upgrades required by RPS projects cannot be quantified at this time, pointing out that a detailed methodology for calculating such benefits is being developed in another phase of this proceeding.

PG&E argues further that reductions in line losses should not be considered network benefits to be netted against transmission costs, because line losses are already allocated to the generators through Meter Multipliers. It maintains that line loss reductions cannot be counted as a benefit unless the generators are willing to lower the power cost commensurately.

TURN agrees with CalWEA that the increase in network transfer capability due to transmission upgrades is relevant and should be assigned value for purposes of a transmission cost bid adder. TURN urges the Commission to develop methods for estimating the value of new transmission projects in the integrated planning envisioned in R.04-01-026. TURN proposes an interim valuation methodology which would estimate the benefits of new network transfer capacity in excess of what an RPS project would need, with the value to be set at half the pro rata cost of the incremental transmission capacity.

CEERT agrees in general with the proposal in the ALJ ruling that network benefits not be litigated at this time but be reserved for future debate. In CEERT's view, the proposed interim methodology provides sufficient flexibility so that network benefits for most bids may be considered at the "back end" of the process. It proposes, however, that developers who believe that transmission upgrades related to their projects could confer significant system benefits be provided the option to have their bid ranked two ways: first with no network benefits assumed and then with the bidder's assumptions about benefits. If acceptance/rejection of the bid depends on whether system benefits are considered, the utility evaluating the bids would determine whether to consider system benefits, document that choice, and provide that documentation to the bidder, the Commission, and the Procurement Review Group (PRG). CEERT believes that at that point the normal review process and/or a generic dispute resolution process should be able to resolve the issue, if necessary, without creating any unmanageable complexity or delay. PG&E responds that CEERT's proposal would lead to unacceptable delay and is contrary to PG&E's position that network benefits should not be considered.

2. Discussion

A general requirement that network benefits be quantified for use in the rank ordering of RPS bids should not be adopted at this time. Contrary to PG&E's and SCE's interpretation, § 399.14(a)(2)(B) would allow transmission costs to be considered net of established benefits in the ranking process. Also contrary to PG&E's statement during the PHC, our determination in D.03-07-033 that evaluation of network benefits for purposes of § 399.25 should be undertaken during a certificate proceeding in no way limits our ability to consider network benefits in other forums for other purposes, including the RPS procurement process. However, there is not adequate information to establish for purposes of the interim RPS procurement whether network benefits would occur due to specific network upgrades. Nor do the analytical tools exist at this time to quantify such benefits. We intend to consider network benefits in future RPS solicitations to the extent feasible. In particular, we expect that the development of a methodology for assessment of the economic benefits of transmission projects, which is underway in another phase of this proceeding, will be useful in this regard.

CalWEA's urging of the adoption of a blanket assumption that the benefits of transmission upgrades for 230 kV and higher systems are equal to or exceed the costs of such upgrades is unrealistic. As other parties have pointed out, the Commission does not utilize such an assumption in our consideration of other transmission projects. Nor should we adopt such a blanket assumption for the utilities' least-cost, best-fit analysis of RPS bids.

We agree with the ALJ ruling that holding evidentiary hearings on network benefits before the initial RPS procurement is not desirable. As CalWEA has acknowledged, network benefits are not easily quantifiable and some may not be near term. In light of the long history and on-going efforts to quantify economic benefits of transmission upgrades, such an undertaking would be unlikely to yield usable results without significant delay of the initial RPS procurement. Such delay would hamper the Commission's ability to meet its accelerated RPS goals. Given that the ability or a method to quantify network benefits has not been established, CalWEA's suggestion that network benefits be assessed on the basis of witness affidavits is also unworkable.

For the same reasons, we do not adopt CEERT's suggestion that the utilities be required to rank a project bid on the basis of the proponent's assumptions about possible network benefits. Disputes between the developer and the utility over potential network benefits, which we view as likely based on the extensive debate to date, would return to the Commission for resolution. The Commission would be in precisely the position it is in now, with no objective basis for assessing the merits of either side.

Similarly, TURN's suggestion that the benefits of increased network transfer capacity be valued at one half the pro rata cost of the incremental capacity, while perhaps more objective than CalWEA's and CEERT's proposals, should not be adopted because it is arbitrary.

Recognizing the complexities involved, D.03-06-071 established the goal that transmission cost estimates used in the procurement process reflect a workable approximation of transmission upgrade costs. The approach in D.03-06-071, in which bidders may describe expected network benefits in their bids and the utility must consider this information in evaluating the bid, is a reasonable approach at this time. While we do not adopt specific instructions regarding the evaluation of network benefits, particular projects may provide clear benefits to the transmission system. We direct the utilities to consider this prospect in evaluating bids. As specified in Attachment A, the utility's consideration of potential network benefits should be consistent and transparent.

D. Curtailment as a Means to Reduce Transmission Costs

Under the approach proposed in the ALJ ruling, the utilities would develop transmission cost estimates for their Transmission Ranking Cost Reports that allow delivery of the full output of the renewable projects. If a project has System Impact Studies and Facilities Studies that do not address deliverability needs, the utility's transmission cost estimates in the Transmission Ranking Cost Report would still include deliverability costs, unless a contract has been signed that provides for curtailment in lieu of full deliverability. Projects would be allowed to submit bids that provide for less-than-full deliverability of project output, e.g., curtailments when transmission is constrained. The utility would then assess, on a case-by-case basis, whether and the extent to which the published transmission cost estimates should be modified in assessing such projects' bids.

1. Positions of the Parties

CalWEA asserts that the ALJ ruling's proposed treatment of curtailable projects does not take into account a generator's right to avoid network upgrade costs. It maintains that generators have an unqualified right under FERC's Standard Large Generator Interconnection Procedures, established in FERC Orders 2003 and 2003-A, to interconnect as an Energy Resource and use the as-available transmission capability of the transmission provider. Alternatively, the generator may choose to be interconnected as a Network Resource.[3]

---

[3] In FERC's Standard Large Generator Interconnection Agreement, Network Resource Interconnection Service would allow the generator to integrate its facility with the transmission provider's transmission system in a manner comparable to that in which the transmission provider integrates its own generating facilities to serve native load customers. Energy Resource Interconnection Service would allow the generator to use

Footnote continued on next page

CalWEA asserts that utilities should not be given the discretion, as proposed in the ALJ ruling, to determine whether transmission cost estimates should be modified for projects that choose interconnection as an Energy Resource. CalWEA maintains that the Commission should require that a lower transmission cost adder be used if, by opting for Energy Resource treatment, the generator causes lower cost (or zero cost) transmission upgrades.

---

existing firm or non-firm capacity on the transmission provider's transmission system on an as-available basis. In essence, Network Resource energy would be fully deliverable, whereas Energy Resource energy would be curtailable when necessary to accommodate limitations on the transmission provider's system.

In CEERT's view, the treatment of curtailability proposed in the ALJ ruling provides sufficient flexibility for most bids regarding curtailability, which would be considered at the "back end" of the process. CEERT proposes, however, that developers who believe that curtailment/generator dispatch is an appropriate alternative to transmission expansion be provided the option to have their bid ranked both ways, i.e., with and without the bidder's assumptions about project curtailability. CEERT maintains that many transmission paths are congested only 10 to 50 hours per year and that it makes little sense to require a bidder whose project could otherwise deliver 99 to 99.5% of its energy to support an expensive upgrade that may be used less than 1% of the time. CEERT recommends that, if acceptance of a bid depends on whether curtailment/generator redispatch is considered, the utility evaluating the bids should be required to determine whether to accept curtailment/generator redispatch, document that choice, and provide that documentation to the bidder, the Commission, and the PRG. CEERT believes that at that point the normal review or dispute resolution process should be used to resolve the issue, if necessary.

TURN agrees with CEERT and CalWEA that the utilities should model transmission costs with and without curtailment provisions. In its view, if modest levels of curtailment would avoid a substantial transmission investment, this option should be considered in evaluating total bid costs. TURN suggests that bidders desiring curtailability be directed to specify the maximum level of acceptable curtailment, with bid prices submitted in connection with a curtailment offer assuming the maximum level of acceptable curtailment. TURN recognizes that the capacity value of such resources may be downgraded as part of the resource adequacy determinations ongoing in R.01-10-024.[4]

PG&E points to the "challenges" of relying on curtailment and redispatch options for purposes of transmission planning. PG&E maintains that, while dispatchability and curtailability may be helpful in matching aggregate resource levels to aggregate load levels, curtailment or generator redispatch can have undesirable effects when used to avoid building needed transmission upgrades. PG&E submits that the ISO would have to approve reliance on such schemes in lieu of transmission upgrades as part of the interconnection process, which would require much more detailed studies than are contemplated by the ALJ ruling. PG&E suggests that renewable generators can request an interconnection study through the ISO interconnection process and submit the resulting transmission cost estimates with their bids. PG&E raises an additional concern that, if resources are not available due to inadequate transmission capability, load may be curtailed. PG&E does not believe that the Legislature intended to compromise reliability when it mandated the RPS process.

SDG&E describes that, in addition to a reduction in transmission costs, curtailability could reduce expenditures for Firm Transmission Rights or, under the new market design, Congestion Revenue Rights,[5] and could reduce losses on the resale of power sold to avoid congestion. SDG&E submits, however, that these benefits would be extremely difficult to quantify for the term of a contract

---

[4] Resource adequacy determinations are being made in R.01-10-024 and its successor rulemaking R.04-04-003.

[5] The holders of Firm Transmission Rights or Congestion Revenue Rights would receive the revenue associated with transmission congestion.

and that analyzing each bid with and without transmission upgrades would dramatically increase the analytical effort for bid evaluation. SDG&E argues further that the delivery from a curtailable resource would be unknown, frustrating a utility's ability to plan for attainment of its RPS annual goals.

2. Discussion

CalWEA's assertion that generators have a right to interconnect as an Energy Resource or a Network Resource is not consistent with current practices in California. The distinction in FERC's Standard Large Generator Interconnection Agreement between Network Resource Interconnection Service and Energy Resource Interconnection Service is based on eastern ISOs which have capacity markets and thus two levels of transmission service. These options are not offered in California through the ISO's tariffs.

In D.03-06-071, we recognized that the utilities may favor curtailability and dispatchability as attributes of bids. At the same time, we support the establishment of a deliverability standard in California, which would enable generators to meet the utilities' reserve requirements established in D.04-01-050. We support the ability of the utilities, with regulatory approval, to build and pay for, on a rolled-in basis, transmission system upgrades necessary to provide full deliverability of a generator's output. Until there is a deliverability standard, the utilities should assess RPS bids that propose curtailability as an attribute of their projects on a case-by-case basis. We do not require that they perform bid rankings with and without curtailability assumptions, as CEERT requests.

The guidelines in the ALJ ruling do not specify how, in this first year, a utility should assess transmission costs for projects that propose curtailability as an alternative to transmission upgrades or how it should value such bids. The best method of determining the feasibility of curtailability proposals appears to be through System Impact Studies and Facilities Studies. We direct the utilities to evaluate bids for projects that demonstrate reliable curtailability through such studies on that basis.

The same degree of certainty cannot be obtained from the conceptual studies used to evaluate transmission needs of projects without System Impact Studies or Facilities Studies. As a consequence, we do not order the utilities to evaluate curtailability proposals that rely only on the conceptual studies. However, on a case-by-case basis, there may be real benefits to ratepayers if generation can be curtailed in some limited amount and thus avoid costly transmission upgrades. For this year, the utility may use its judgment in evaluating these potential benefits, subject to the guidance expressed herein and the adopted dispute resolution process. Curtailability benefits may be captured more accurately in subsequent years' transmission cost analyses.

While we will give latitude to the judgment of the utility in this regard for projects that do not have System Impact Studies or Facilities Studies, we do not want to impose unnecessary transmission costs or prevent otherwise desirable projects from going forward if limited amounts of curtailability can in fact be managed. Like network benefits, the utility should document that it has considered curtailability proposals in a manner that is consistent and transparent to the Commission when it reviews proposed RPS contracts.

E. Dynamic Line Ratings

The ALJ ruling would reject CalWEA's recommendation that dynamic line ratings be used in the transmission cost estimates. In its comments, CalWEA reiterates its view that, by taking wind conditions into account, transmission requirements for wind generators can be reduced substantially. CalWEA submits that dynamic ratings are presently in use in multiple portions of the ISO grid.

SDG&E and SCE support the treatment of line ratings in the ALJ ruling. SDG&E submits that the application of dynamic line ratings is very specific to climate and other locational factors and is based on many months of studies even for a single line. It maintains that the use of dynamic line ratings is largely experimental and has not been accepted for day-to-day operations. It points out that the analysis needed to use dynamic ratings goes well beyond the level of analysis in the conceptual studies. SCE maintains that dynamic ratings would not be appropriate in the Tehachapi area, for example, because wind does not blow uniformly along the path of the transmission routes being considered.

We conclude that dynamic line ratings should not be used in determining needed transmission upgrades for purposes of evaluating the first RPS bids. Typical ambient conditions are taken into account in establishing line ratings for planning purposes. Dynamic line ratings, by their nature, reflect operating conditions that are not pervasive enough to be considered in reliability planning studies. We recognize, however, that dynamic line rating technologies are evolving, and we leave open the possibility that future RPS bid evaluations may appropriately incorporate them.

F. Generation or Consumption of VARs

The ALJ ruling would reject CalWEA's suggestion that expected VAR characteristics of wind generators be taken into account in development of transmission cost estimates. Except for projects with completed System Impact Studies and Facilities Studies, the utilities are to develop transmission cost estimates without reference to specific projects. Developers would be allowed to submit VAR characteristics of their proposed projects, to the extent known, as part of their bids, and the utilities would be allowed to take this information into account in assessing the bids.

1. Positions of the Parties

In comments, CEERT and CalWEA express concern that, in the conceptual studies, the utilities may have modeled wind generators as large VAR consumers and thus may have assumed the need for external devices to provide extra voltage support or may have underestimated the transfer capability of transmission lines designed to serve wind generators. They point out that current FERC policy requires that all generators, including wind generators, be roughly equivalent in voltage support obligations. CalWEA describes that modern wind designs employ static VAR compensators and capacitor banks to provide VARs that are closely calibrated to the VAR consumption of the machines and to the VAR needs of the local grid. CalWEA explains that these modern designs can provide voltage support benefit even when wind generators are not producing power, a capability not conferred by synchronous generators. CalWEA submits that the utilities should be required to assume that wind generators can operate within industry VAR requirements normally imposed on synchronous generators and that the ability of modern wind designs to provide voltage support should be reflected in transmission cost estimates.

PG&E states that it does not disagree with the proposal in the ALJ ruling that developers be allowed to submit VAR characteristics as part of their bids and that utilities be authorized to take this information into account in assessing the bids. In its opinion, however, it is unlikely that the value of VAR support would justify an adjustment of the transmission cost adder. SCE expresses a similar view.

2. Discussion

Comments on the ALJ ruling raise two separate VAR-related issues: (1) whether in developing transmission cost estimates the utilities should assume that wind generators will be net consumers of VARs, and (2) whether generators should be allowed to document in their bids that they will be net producers of VARs and have their bid value adjusted upward commensurately.

Regarding the first concern, in estimating transmission costs in the Transmission Ranking Cost Reports the utilities should assume that wind generators will utilize modern technologies that employ VAR compensators and capacitor banks, in accordance with industry standards. Thus, they should not increase transmission costs assessed to wind bids due to concerns that the projects may be VAR consumers. Second, the utilities should consider any proposals they receive for VAR production as they assess the RPS bids.

G. Coincident Generation

In its comments, CalWEA submits that the sizing of transmission facilities should take into account the fact that maximum coincident generation from clusters of wind generation is materially less than nameplate generation, with the difference for a large resource area like Tehachapi being approximately 15%. This issue was not addressed in the ALJ ruling. CalWEA submits that utilities routinely consider load diversity in designing transmission and distribution systems and that diversity of wind generation similarly should be factored into the transmission cost determination. CalWEA maintains that, for example, SCE has not taken this factor into consideration in its conceptual studies for Tehachapi. SCE responds that the coincidence factor does not reduce the cost of facilities by 15% and that the cost estimates in SCE’s conceptual plan for

Tehachapi properly reflected the expected costs of facilities needed to interconnect wind generation.

CalWEA raised this issue for the first time in its comments on the ALJ ruling. We do not have sufficient information to determine whether or the manner in which the coincidence of wind generation should be taken into account in planning transmission upgrades for wind generation. As a result, we do not require that the utilities modify their conceptual studies in this regard. However, we would be willing to consider this matter as a possible refinement in development of future Transmission Ranking Cost Reports.

H. Phasing of Transmission Additions

As described in the ALJ ruling, transmission cost estimates should reflect phased upgrades, with the most cost-effective upgrades assumed to be built first. No party took issue with this general approach. There were comments, however, regarding the manner in which information regarding the phasing of transmission additions should be reported in the Transmission Ranking Cost Reports.

PG&E's transmission cost proposal submitted in R.01-10-024 anticipated that three levels of transmission cost estimates for each geographic cluster of renewable projects would be included in the Transmission Ranking Cost Report. The methodology proposed in the ALJ ruling would increase the number of levels of possible transmission development to be reported.

In PG&E's proposal submitted in R.01-10-024, the base level of transmission capacity identified as Level 1 would reflect the available transmission capacity taking into account all upgrades planned for generation projects in the ISO interconnection queue. PG&E's suggested Level 2 would reflect the lowest-cost (or most cost-effective) network upgrade after upgrades for projects in the ISO interconnection queue, and PG&E's suggested Level 3 would include the combined capacity of all additional network upgrades needed to accommodate the entire cluster of renewable generation.

In the methodology in the ALJ ruling, the base level of reported transmission capacity (Level 1) would be the excess capacity expected to be available excluding any upgrades planned for projects in the ISO interconnection queue. Level 2 transmission capacity would reflect the capacity expected to become available due to upgrades for the first project in the ISO interconnection queue for which transmission upgrades are needed, with an additional level created for each project in the ISO interconnection queue for which needed transmission upgrades have been identified. Subsequent levels (identified as Level 3 in the ALJ ruling assuming one project in the ISO queue with needed transmission upgrades) would reflect the transmission capacity expected to become available with the lowest-cost (or most cost-effective) network upgrade in addition to upgrades for projects in the ISO interconnection queue, with an additional level created for each network upgrade needed to accommodate the total amount of generation in the identified cluster.

1. Positions of the Parties

In its comments on the ALJ ruling, PG&E states that it agrees with the portion of the ALJ proposal that would require separate reporting for each distinct network upgrade needed to accommodate renewable projects not in the ISO interconnection queue. PG&E takes issue, however, with the proposed requirement that the utilities separately identify the available transmission capacity excluding upgrades for projects in the ISO interconnection queue and the transmission capacity created by each upgrade planned for projects in the ISO interconnection queue. PG&E maintains that this level of detail has no apparent purpose. Because PG&E's existing conceptual studies included all transmission capacity planned for projects in the ISO queue, PG&E maintains that it may not be practicable to report Level 1 and Level 2 transmission capacities and costs separately as proposed in the ALJ ruling.

In its reply comments on the ALJ ruling, CEERT agrees in part with PG&E's recommendation that the utilities not be required to "back out" from the Level 1 base case those transmission upgrades planned to accommodate generation projects in the ISO queue, to the extent that such generation projects are non-renewable or are not associated with a planned RPS solicitation.

CalWEA agrees with the approach in the ALJ ruling. It points out that if a generation project in the ISO queue fails, the cost of network upgrades currently planned for that project may be imposed on the next generator that is in the same cluster area. In its view, the objective of the Transmission Ranking Cost Report is to report all upgrade costs associated with a cluster. In addition, to the extent generators already in the queue bid in the auction, the upgrades associated with those generators should be reflected in the bid adder for those projects. CalWEA is concerned that PG&E's approach would not allow the cost of network upgrades associated with generators in the ISO queue to be reflected in their bid adders.

2. Discussion

We confirm that the Transmission Ranking Cost Reports should include separate reporting for each distinct network upgrade needed to accommodate renewable projects that have not had transmission upgrades identified through System Impact Studies or Facilities Studies, consistent with the ALJ ruling. Because of feasibility concerns raised by PG&E, we do not require (but would allow) the utilities to separately identify in their Transmission Ranking Cost

Reports a base case that excludes transmission capacity identified through System Impact Studies and Facilities Studies for projects in the ISO queue and, thus, included in the base cases in their conceptual transmission studies.

CalWEA is correct that some of the projects in the ISO queue may not ultimately be built, with the effect that the costs associated with necessary transmission may be attributed to the next project in line to interconnect. However, the transmission costs of projects with completed System Impact Studies and Facilities will not be ignored in the adopted bid adder process. Costs identified in System Impact Studies and Facilities Studies, adjusted if needed for deliverability as discussed in Section III.D, will be used in developing the bid adder for the project in question.

While we do not require that the utilities report a base transmission case excluding projects in the ISO interconnection queue, they should still report the results of existing System Impact Studies and Facility Studies for projects in the ISO queue. In particular, the utilities should describe each planned transmission upgrade and provide cost estimates. This will facilitate verification of bid adders for these projects, including any adjustments to provide deliverability, and will allow better understanding of other portions of the Transmission Ranking Cost Reports.

I. Transmission Costs for Projects Whose Output May Be Sold to Another Entity

The ALJ ruling would require that each utility that was notified in its April 2, 2004 request for information that a project in its service territory is contemplating a bid to sell power to another entity should include in its Transmission Ranking Cost Report an estimate of transmission upgrade costs needed to deliver the power to the adjoining transmission system specified by the project developer. The ruling would require that a developer bidding to sell its power to another entity include with its bid an estimate of transmission upgrade costs needed to deliver the power to the purchasing utility. It specified that transmission costs to deliver the power to the purchasing utility, including wheeling costs in non-ISO control areas, would not be used in the first ranking of bids.

1. Positions of the Parties

PG&E disagrees with the ALJ ruling regarding the treatment of wheeling costs in non-ISO control areas. Noting that the only available revenue stream for a generator to recover such costs is through the generator's contract with the utility, PG&E states that wheeling costs paid to non-ISO control areas should be internalized into the bid, similar to gen-tie costs, and should be considered in the first ranking of the bids. PG&E states that exclusion of wheeling charges from Supplemental Energy Payments can be facilitated by identifying such charges separately in the bid. PG&E agrees with the ALJ ruling that all transmission costs related to the ISO-controlled grid, whether incurred by the purchasing utility or by another utility whose system is traversed, should be used in the second ranking process.

In reply comments on the ALJ ruling, TURN agrees with PG&E that transmission wheeling costs incurred by out-of-state generators should be included in the bid price and included as part of the first ranking process. TURN takes issue, however, with PG&E's apparent view that Supplemental Energy Payments cannot be used to cover out-of-state transmission expenses. In

TURN's opinion, § 399.15(a)(2) only prohibits the award of Supplemental Energy Payments for transmission upgrades made by a California electric utility.[6]

2. Discussion

No party took issue with the method by which the ALJ ruling would require a subject utility would develop transmission costs for projects whose output may be sold to another utility. We agree that each utility that was notified in response to its April 2, 2004 request for information that a project in its service territory is contemplating a bid to sell power to another entity should include in its Transmission Ranking Cost Report an estimate of transmission upgrade costs needed to deliver the power to the adjoining transmission system specified by the project developer. The developer should then list that cost separately in its bid documentation.

We agree with PG&E regarding the treatment of wheeling costs in the bid ranking process. Because wheeling charges for the transport of power through non-ISO control areas are a cost to the developer, they should be included in the bid price so that the contractual revenue stream based on the bid price is sufficient to cover these costs. Because they are a cost to the developer, we see no reason why wheeling costs would not be eligible for Supplemental Energy

---

[6] As TURN notes, § 399.15(a)(2) provides as follows: "The Energy Commission shall provide supplemental energy payments from funds in the New Renewable Resources Account in the Renewable Resource Trust Fund to eligible renewable energy resources pursuant to Section 383.5, consistent with this article, for above-market costs. Indirect costs associated with the purchase of eligible renewable energy resources, such as imbalance energy charges, sale of excess energy, decreased generation from existing resources, or transmission upgrades shall not be eligible for supplemental energy payments, but shall be recoverable by an electrical corporation in rates, as authorized by the commission."

Payments pursuant to § 399.15(a)(2). To aid in bid assessment, developers should list expected wheeling charges separately in their bids.

No party took issue with the provision in the ALJ ruling that transmission upgrade costs incurred if power traverses the network of a utility in the ISO-controlled grid should be used in the second ranking process. We agree that this approach is reasonable, but clarify the relevant language in Attachment A.

J. Preparation of the Transmission Ranking Cost Reports

The ALJ ruling proposed that the utilities be required to file their Transmission Ranking Cost Reports within 14 days after Commission adoption of guidelines for preparation of the reports. SCE submits that 14 days is likely to be insufficient, even if utilities have all of the information needed from potential RPS generators well before a Commission order. SCE requests that each utility be given 21 days after it has received follow-up information from potential RPS generators or the Commission order, whichever is later. No party responded to SCE's request.

By previous ruling, the ALJ required that the utilities request no later than April 2, 2004 any additional information they may need from prospective RPS bidders, that interested developers respond within 15 calendar days, and that the utilities prepare additional conceptual transmission studies, if needed, based on the developers' responses. We expect that the utilities have complied with this ruling and have completed their conceptual studies. In today's decision, we reject several proposals that would have increased the effort required to estimate transmission costs, so that the adopted requirements for the Transmission Cost Ranking Reports are based largely on the completed conceptual studies. As a result, we believe that 14 days from the effective date of this order provides sufficient time for the utilities to prepare and file their Transmission Ranking Cost Reports.

K. Bids for which Transmission Costs Have Not Been Estimated

In its comments, TURN notes that the ALJ ruling did not address the treatment of unanticipated renewable bids that the utilities did not consider in development of transmission cost estimates. TURN recommends that, if a utility receives a bid from a project that was not considered in the Transmission Ranking Cost Report and has not received System Impact and Facilities Studies, the bid still be eligible for consideration, with its treatment in the second ranking based on the utility's best estimate of potential transmission upgrades.

SDG&E replies that TURN's approach would provide bidders an incentive not to submit timely and sufficient information to the utilities for the preparation of transmission cost estimates. SDG&E recommends that, if the Commission adopts TURN's proposal, only bidders that were not on the utilities' distribution list for their April 2, 2004 request for information be allowed to bid in the absence of a previously determined transmission estimate applicable to their project.

PG&E agrees with TURN that, as a general principle, projects that were not studied prior to completion of the Transmission Ranking Cost Reports should be eligible for the RPS solicitation. Because the conceptual studies are based on project size and location, the Transmission Ranking Cost Report can be used to estimate transmission costs for any bidder that provides basic information regarding its project. PG&E is concerned, however, that it is not practicable to consider a bid that wishes to use an interconnection point that was not considered in the Transmission Ranking Cost Report. PG&E maintains that estimating transmission costs for a new project based on an interconnection point not available to other developers would be unfair to the other bidders, would introduce more disputes, and could delay RPS procurement. Therefore, PG&E recommends that bids be evaluated based only on interconnection points already analyzed in the Transmission Ranking Cost Report.

PG&E's suggested limitation on TURN's approach provides a proper balance that would further the goal of obtaining the least-cost, best-fit renewable resources while not introducing complications that could unnecessarily delay completion of the procurement process. We conclude that it is reasonable to allow developers to bid who have not previously notified the utilities of their existence, but that all bids should be limited to interconnection points analyzed in the Transmission Ranking Cost Reports.

L. Consideration of Transmission Costs in Rank Ordering of Bids

Consideration of transmission costs in the rank ordering of RPS bids will entail an iterative process, as detailed in Attachment A. The ALJ ruling proposed that, within a geographic area, or "cluster," the utility would assign network upgrade costs to specific renewable bidders according to (1) their place in the ISO interconnection queue (for projects with completed System Impact Studies and Facilities Studies) or (2) their rank ordering without consideration of the purchasing utility's transmission upgrade costs. The utility would then undertake the least-cost second ranking of bids among all clusters, subject to best-fit considerations, to minimize total costs of power from RPS projects, including the cost of needed transmission upgrades.

In Section III.I of this order, we modify the proposal in the ALJ ruling regarding the treatment of transmission costs for delivering power from an out-of-area bidder to the purchasing utility. With the exception of that issue, no party took exception with the ALJ ruling regarding the iterative process for rank ordering RPS bids. With the adopted modifications, the rank ordering process in the ALJ ruling is reasonable.

The ALJ ruling described that the appropriate form of the transmission cost estimate used in assessing a bid, i.e., total cost, per-megawatt cost, or per-kilowatt-hour cost, may depend on the form of the bid. Each utility would be required to structure and apply transmission cost estimates in a manner that is consistent and transparent to the Commission when it reviews proposed RPS contracts. In its comments on the ALJ ruling, SCE states that the utilities should use an annual revenue requirement covering both capital expenses and operation and maintenance (O&M) costs, to reflect the total costs ratepayers will ultimately pay. SCE explains that O&M would include costs such as administrative and general costs, insurance, and property taxes. It also proposes that capital costs include the costs of financing during construction ("allowance for funds used during construction," or AFUDC) to determine the total rate base cost estimate. These costs would then be converted to a revenue requirement stream over the useful life of the asset.

As a general matter, it would be desirable to have consistent cost estimates for assessing RPS projects, regardless of whether the upgrades were identified through System Impact Studies and Facilities Studies or through the utilities' conceptual studies. However, costs have not been developed at the same level of detail or accuracy in the two types of studies. Additionally, we expect that AFUDC and O&M costs will be minimal, so that their inclusion or exclusion would be unlikely to change the relative position of RPS bids. We will allow, but not require, the utilities to modify the conceptual studies' cost estimates if the System Impact Studies and Facilities Studies contain AFUDC and/or O&M cost components that were not considered in the conceptual studies. If a utility makes such modifications, it should document the changes fully in its Transmission Ranking Cost Report, including a demonstration that these cost components were included in System Impact Studies and Facilities Studies and that consistent changes were made to the conceptual study cost results.

According to the ALJ ruling, the utilities would consider the entire cost of a transmission upgrade in ranking the projects that would use the upgrade. This approach is consistent with D.03-06-071, which provided that, at least in the near term, the full cost of network upgrades should be considered in application of the least-cost criterion. We will consider whether to refine this approach in later procurements.

We are concerned, in particular, that allocating the entire cost of a large transmission upgrade to the projects that have bid in response to one year's procurement solicitation does not take into account that, in some areas, the most cost-effective transmission upgrade may be large enough to accommodate more than one year's bidders. Considering the entire cost in assessing one year's bids may make it difficult for such projects to ever win the bid or for the needed transmission upgrade to be built.

During the PHC, an approach was discussed in which only a portion of the cost of a large transmission upgrade would be assessed in evaluating RPS bids if a threshold amount of projects have bid that would use the upgrade. The proposed decision issued on March 2, 2004 in the Tehachapi phase of this proceeding recommends that a study group examine the use of similar triggers for phased transmission upgrades in that region. Building on that concept, it may be desirable to reflect costs of a large transmission upgrade on a pro rata basis in the rank ordering of individual bids if a trigger mechanism has been adopted for construction of the transmission upgrade and sufficient bids have been received to initiate construction of the upgrade consistent with the trigger mechanism. We plan to explore whether these or other approaches could be adopted to improve the application of transmission cost adders in areas with large renewable resource potential.

M. Confidentiality

Parties expressed concern at the PHC that sensitive information regarding renewable projects not be divulged. The ALJ ruling invited parties to address in their comments whether confidentiality requirements should be adopted. However, no party addressed this matter in its comments. As a result, we do not impose confidentiality requirements on any part of the adopted process for developing and considering transmission costs in the assessment of RPS bids.

N. Dispute Resolution

In D.03-06-071, we provided that renewable developers will have the opportunity in this proceeding to dispute the results of transmission cost assessments.

In its PHC statement, CalWEA suggested an expedited dispute resolution mechanism or the dissemination of transmission cost information before Transmission Ranking Cost Reports are released as a means to speed evaluation of the utilities' transmission cost analyses. SDG&E suggested that a consultant be retained to resolve disputes.

The ALJ ruling did not recommend creation of a new dispute resolution mechanism and would instead allow parties to file comments on the utilities' Transmission Ranking Cost Reports. We adopt this process here, and provide that initial comments on the Transmission Ranking Cost Reports may be filed within seven days of the due date for the reports and reply comments may be filed within seven days thereafter. Consistent with the ALJ ruling, the

Commission will then assess the adequacy of the reports on the basis of the filed comments and determine whether additional steps are warranted before the utilities' results are used in ranking bids for the initial RPS procurement. We delegate this responsibility to the Assigned Commissioner in this proceeding, so that the bid ranking process is not delayed by the time that would be necessary to bring disputes to the full Commission.

We also provided in D.03-06-071 that, following Procurement Review Group analysis, each utility should file an advice letter for Commission approval of its proposed contracts. PRG members and other parties will be allowed to raise transmission-related or other concerns in protests to those advice letters.

In its comments, TURN urges the Commission not to rely on protests from Procurement Review Group members as a method of handling disputes over transmission cost adders. TURN submits that it is unreasonable to expect non-market participants like TURN to independently review the transmission cost estimates for each bidder. TURN is also concerned that, once the utility has submitted contracts for approval, the Commission may be hard-pressed to deny the advice letters due to disputed calculations of the transmission cost adders. The opportunity for parties to file comments on the Transmission Ranking Cost Reports and for disputes to be resolved before the bids are evaluated should obviate much of TURN's concerns.

III. Comments on Draft Decision

The draft decision of the assigned ALJ was mailed to the parties in this proceeding in accordance with Section 311(g)(1) and Rule 77.7 of the Rules of Practice and Procedure. Comments and/or reply comments were filed by PG&E, CalWEA, SDG&E, CEERT, and TURN. Two issues were raised in comments that merit attention here.

In their initial comments, CalWEA and TURN raise concerns regarding the draft decision's suggested method of allowing project developers to collaborate and potentially share the cost of gen-tie facilities needed to deliver their power. TURN is concerned that the proposed method of requiring the utilities to post the name, project location, and first point of interconnection of project on the web raises issues of confidentiality. Both parties are concerned that the subsequent opportunities for renegotiation of bids will unfairly advantage certain bidders over others, and risk harm to ratepayers. While we believe it would be feasible to design a system that would overcome these concerns, we note the urgency of establishing a clear method of bid evaluation in advance of the pending RPS solicitations.

TURN's alternative proposal is workable, and we adopt it. Under this approach, each bidder may at its option list its estimated gen-tie costs separately, and the utility will make iterative adjustments to its bid ranking to account for sharing of these costs among those bidders who are selected. While we recognize the extra analytic burden this requirement places on the utilities, they are directed to make their best efforts to find these cost-sharing opportunities, which, to the extent they can be captured, will result in lower costs to ratepayers. The utilities should present the results of this analysis to their Procurement Review Groups for review.

CalWEA also notes an inconsistency between the draft decision's discussion of network benefits and the language of D.03-06-071. D.03-06-071 stated the following (p.36):

> It is conceivable that the addition of renewable generation to the grid may result in network benefits, and bidders are encouraged to describe any such potential benefits in their responses…The utilities should make it known in their annual plans that such benefits are sought, should apply transparent

criteria in evaluating such claims, and should present the results of these evaluations to their PRGs for consideration."[7]

CalWEA notes that the word "should" has changed to "may" in the draft decision's discussion of how the utility will consider possible network benefits. While we recognize that the Commission has not yet developed a methodology for considering network benefits, we do not want to eliminate the possibility that such benefits could be made evident in the course of evaluating particular RPS bids. We do not want to miss clear-cut opportunities to benefit the network via the addition of particular renewable energy resources. Accordingly, we direct the utilities to develop consistent, logical approaches to assessing these potential benefits, to the level of detail that is feasible over the course of this year's RPS solicitation. This evaluation process should be transparent to the utility's Procurement Review Group and to the Commission. We modify the language in the draft decision and Appendix to reflect this change.

IV. Assignment of Proceeding

Loretta M. Lynch is the Assigned Commissioner and Charlotte F. TerKeurst is the assigned ALJ in this proceeding.

Findings of Fact

1. For the initial RPS procurement, it is reasonable to evaluate transmission costs of renewable projects using System Integration Studies and Facility Studies and to rely on existing conceptual transmission studies to the extent that System Impact Studies and Facilities Studies do not exist or are not sufficient.

---

[7] This direction was encapsulated in Finding of Fact 34 and Ordering Paragraph 18 of D.03-06-071.

2. For the initial RPS procurement, it is reasonable to require that each utility describe in its Transmission Ranking Cost Report each transmission upgrade identified in its conceptual studies that may be shared by renewable projects but which the utility considers to be gen-ties, and the basis for this conclusion.

3. For the initial RPS procurement, it is reasonable to require that each bidder be given the opportunity to list its gen-tie costs separately in its bid, and each utility should seek opportunities for the sharing of gen-tie costs among selected bidders.

4. For the initial RPS procurement, it is reasonable to allow bidders to describe expected network benefits in their bids and to require the utilities to consider this information in evaluating the bids in a method that is consistent and transparent.

5. For the initial RPS procurement, it is reasonable to allow the utilities to assess RPS bids that propose curtailability as an attribute of their projects on a case-by-case basis, subject to the requirement that such consideration be documented in a manner that is consistent and transparent to the Commission when it reviews proposed RPS contracts.

6. It is reasonable to require the utilities to assume in estimating transmission costs that wind generators will utilize modern technologies that employ VAR compensators and capacitor banks, in accordance with industry standards and, thus, to not increase transmission costs assessed to wind projects due to concerns that the projects may be VAR consumers.

7. It is reasonable to allow wind developers to include in their bids documentation that they will be net producers of VARs and to require the utilities to consider any such proposals they receive on a case-by-case basis.

8. It is reasonable to require that the utilities include in their Transmission Ranking Cost Reports separate reporting for each distinct network upgrade needed to accommodate renewable projects which have not had transmission upgrades identified through System Impact Studies or Facilities Studies.

9. It is reasonable to allow each utility to report a base case in its Transmission Ranking Cost Reports that includes transmission capacity which was identified through System Impact Studies and Facilities Studies for projects in the ISO queue and included in the base cases utilized in its conceptual transmission studies.

10. It is reasonable to require that the utilities describe in their Transmission Ranking Cost Reports the results of existing System Impact Studies and Facility Studies for projects in the ISO queue.

11. It is reasonable to require that wheeling costs for the transport of power through non-ISO control areas be included in the bid price and in the first ranking of RPS bids. Because of this, it is not necessary for developers to list expected wheeling charges separately in their bids.

12. It is reasonable to require the utilities to prepare and file their Transmission Ranking Cost Reports within 14 days of the effective date of this order.

13. It is reasonable to allow developers to bid who have not previously notified the utilities of their existence; however, all bids should be limited to interconnection points analyzed in the Transmission Ranking Cost Reports.

14. It is reasonable to allow the utilities to modify conceptual studies' cost estimates to be consistent with System Impact and Facilities Studies if the latter include AFUDC and/or O&M cost components that were not considered in the conceptual studies.

15. It is reasonable to delegate to the Assigned Commissioner in I.00-11-001 the assessment of the adequacy of Transmission Ranking Cost Reports required by this order, so that the bid ranking process is not delayed.

16. It is reasonable to adopt the methodology for the development and consideration of transmission costs in the initial RPS procurement contained in the April 2, 2004 ALJ ruling, with the modifications adopted in this order.

Conclusions of Law

1. Section 399.14(a)(2)(B) would allow transmission costs to be considered net of established benefits in the ranking process.

2. The Commission's determination in D.03-07-033 that evaluation of network benefits for purposes of § 399.25 should be undertaken during a certificate proceeding in no way limits our ability to consider network benefits in other forums for other purpose, including the RPS procurement process.

3. The responsibility to assess the adequacy of the Transmission Ranking Cost Reports should be delegated to the Assigned Commissioner in I.00-11-001.

4. The Methodology for Development and Consideration of Transmission Costs in Initial Renewable Portfolio Standard Procurement appended as Attachment A should be adopted, with the further guidance provided in this order.

5. In order to proceed expeditiously with the initial RPS procurement, this decision should be effective today.

INTERIM ORDER

IT IS ORDERED that:

1. We adopt the Methodology for Development and Consideration of Transmission Costs in Initial Renewable Portfolio Standard Procurement

(Interim Methodology) appended as Attachment A and with the further guidance provided in this order.

2. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each prepare and file a Transmission Ranking Cost Report consistent with the Interim Methodology within 14 days of the effective date of this order.

3. Parties may file initial comments on the Transmission Ranking Cost Reports within 7 days of the due date for the Transmission Ranking Cost Reports and may file reply comments within 7 days thereafter.

4. Parties shall file the Transmission Ranking Cost Reports, initial comments, and reply comments in paper form. Parties shall serve the Transmission Ranking Cost Reports and initial comments and may serve reply comments on the service list in electronic form, pursuant to Rule 2.3(b) in the Commission Rules of Practice and Procedure. Parties shall serve paper format copies, in addition to electronic copies, on the Assigned Commissioner, the assigned Administrative Law Judge, anyone on the Appearances and State Service portions of the service list who does not have a valid e-mail address, and any other party requesting paper format copy. For all filings served electronically, the party shall e-mail courtesy copies to the entire service list, including those appearing on the list as "Information Only."

5. The Assigned Commissioner in Investigation 00-11-001 shall assess the adequacy of the Transmission Ranking Cost Reports on the basis of the filed comments and determine whether the reports should be modified or other steps taken before the utilities' results are used in ranking bids for the initial RPS procurement.

6. PG&E, SCE, and SDG&E shall each undertake its initial Renewable Portfolio Standard solicitation and shall consider transmission costs in assessment of the resulting bids in conformance with the Interim Methodology.

7. The Executive Director shall serve a copy of this decision on parties to Rulemaking (R.) 01-10-024, R.04-04-003, and R.04-04-026.

This order is effective today.

Dated June 9, 2004, at San Francisco, California.

MICHAEL R. PEEVEY
President
CARL W. WOOD
LORETTA M. LYNCH
GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners

ATTTACHMENT A
Methodology for Development and Consideration of Transmission Costs in Initial Renewable Portfolio Standard Procurement

Purpose and Applicability

Pursuant to Public Utilities Code Section 399.14(a)(2)(B), the rank ordering and selection of least-cost and best-fit renewable resources for the Renewable Portfolio Standard (RPS) program shall consider estimates of indirect costs associated with needed transmission investments.

Each electrical corporation subject to the Commission's jurisdiction and owning electrical transmission facilities in the State of California (subject utility) shall use this methodology, with further guidance as provided in the Interim Order adopting this methodology, for the development and consideration of transmission costs in ranking bids in response to its initial RPS procurement solicitation.

Direct Assignment Facilities

1. As provided by D.03-06-071, any eligible renewable resource developer bidding in response to an RPS procurement solicitation shall include its expected Direct Assignment Facilities in its bid. The bidder shall internalize in its bid price the estimated cost of all facilities needed to physically and electrically interconnect the renewable energy generation facility to and at the first point of interconnection with the transmission grid. These facilities are referred to as Direct Assignment Facilities or gen-ties.

ATTTACHMENT A
Methodology for Development and Consideration of Transmission Costs in Initial Renewable Portfolio Standard Procurement

2. Direct Assignment Facilities include the transformer bank used to step-up the generation output to transmission voltage, the outlet line between this step-up transformer bank and the transmission system, and any protection and communication facilities needed for interconnection and safe operation of the generator. Direct Assignment Facilities costs need not be separately identified in a renewable resource developer's bid, but may be, at the bidder's discretion.

3. If a bidder elects to list its Direct Assignment costs separately in the bid, the utility shall make iterative adjustments to its bid ranking to account for sharing of these costs among those bidders who are selected.

Network Upgrades

1. Each subject utility shall estimate the cost of its transmission network upgrades needed to accommodate the interconnection or expansion of renewable energy generation facilities and transmission of the projects' output in accordance with these procedures.

2. Network upgrades include all facilities necessary to reinforce the transmission system after the point where a renewable project's electricity first interconnects with and enters the subject utility's transmission grid, and to transmit or deliver the full amount of power from the project. Network upgrades include transmission lines, transformer banks, special protection systems, substation breakers, capacitors, and other equipment needed to transfer power to the consumer.

ATTTACHMENT A
Methodology for Development and Consideration of Transmission Costs in Initial Renewable Portfolio Standard Procurement

3. Each subject utility shall include in its Transmission Ranking Cost Report the cost of all identified network upgrades consistent with this Interim Methodology. Such costs shall not be included in a developer's bid.

Transmission Ranking Cost Report

1. Each subject utility shall prepare a Transmission Ranking Cost Report in which it provides estimates of the capital costs of upgrades to its transmission facilities that would be needed to accommodate interconnection and delivery of power from potential renewable energy bidders in the initial RPS procurement solicitation.

2. Each subject utility's Transmission Ranking Cost Report shall reflect data regarding potential renewable energy bidders obtained through the supplemental solicitations required by the March 19, 2004 Administrative Law Judge's (ALJ) ruling in Investigation (I.) 00-11-040 in addition to previously obtained information regarding potential renewable energy bidders.

3. Each subject utility shall include in its Transmission Ranking Cost Report its transmission cost estimates for the following types of potential renewable energy bidders:

a. Renewable energy resources for which the first point of interconnection with the transmission grid is or will be at a facility owned by the subject utility and whose output is expected to be sold to the subject utility,

ATTTACHMENT A
Methodology for Development and Consideration of Transmission Costs in Initial Renewable Portfolio Standard Procurement

b. Renewable energy resources for which the first point of interconnection with the transmission grid is or will be at a facility owned by the subject utility and whose output is expected to be sold to a different entity, and

c. Renewable energy resources located elsewhere for which the project developer has indicated that it anticipates submitting an RPS bid to the subject utility.

4. Each subject utility shall prepare its Transmission Ranking Cost Report in accordance with the following guidelines:

a. Based upon review of a geographical map, the subject utility shall divide the identified potential renewable energy bidders into clusters based on the substation(s) and bus(es) to which the identified renewable resources most likely would interconnect. If the renewable resource's first point of interconnection is at a substation or bus not owned by the subject utility, the subject utility shall treat that renewable resource as part or all of a cluster beginning at the first point where such added generation would first enter the subject utility-owned transmission system.

b. To identify the network upgrades that may be needed for each cluster, the subject utility shall use the conceptual transmission studies that were submitted for compliance with Senate Bill 1038, conceptual studies prepared pursuant to the March 19, 2004 ALJ ruling in I.00-11-001, and other comparable studies. The utility shall also use any System Impact Studies and Facilities Studies it has for projects in the California Independent System Operator (ISO) interconnection queue. Costs may be adjusted if needed to reflect that construction may occur in a different year than assumed in an existing study.

ATTTACHMENT A
Methodology for Development and Consideration of Transmission Costs in Initial Renewable Portfolio Standard Procurement

c. Each subject utility may modify its conceptual studies' cost estimates to be consistent with cost estimates in System Impact Studies and Facilities Studies, to the extent that the conceptual studies omit but System Impact Studies and Facilities Studies include Allowance for Funds Used During Construction and/or Operation and Maintenance cost components. If a subject utility makes such modifications, it shall document the changes fully in its Transmission Ranking Cost Report, including a demonstration that these cost components were included in System Impact Studies and Facilities Studies and that consistent changes were made to the conceptual study cost results.

d. Each subject utility shall develop transmission cost estimates to provide for delivery of the full output of the renewable projects, except for projects in the ISO interconnection queue with signed contracts providing for curtailment in lieu of full deliverability of their output.

e. Based on the conceptual transmission studies and any available System Impact Studies and Facilities Studies, each subject utility shall identify the transmission network upgrades and their capital costs that are expected to be needed to accommodate each cluster of renewable resources. For each cluster, the subject utility shall identify levels of transmission capacity and related costs according to the following order:

(i) Level 1—the transmission capacity expected to be available, which may include upgrades identified for projects in the ISO interconnection queue with completed System Impact Studies and Facility Studies which were included in the base case in the utility's conceptual transmission studies.

(ii) Level 2—the transmission capacity expected to become available with the lowest cost (or most cost-effective) network upgrade in addition to upgrades included in Level 1. An additional level shall be created for each next most cost-effective network upgrade, with the number of levels depending on the number of network upgrades needed to accommodate the total amount of generation in the identified cluster.

ATTTACHMENT A
Methodology for Development and Consideration of Transmission Costs in Initial Renewable Portfolio Standard Procurement

f. Each subject utility shall develop and include in its Transmission Ranking Cost Report non-binding cost estimates for each level of transmission network upgrades, other than Level 1, and for common facilities needed if renewable generation were added at several clusters simultaneously. For each project in the ISO interconnection queue for which transmission upgrades are included in Level 1, the subject utility shall describe the upgrade and its associated costs.

g. If a developer of a renewable energy resource whose first point of interconnection would be with the subject utility's transmission grid has informed the subject utility that it plans to submit a bid to sell the resource's output to another entity, the subject utility shall identify and include the costs of transmission upgrades needed to transmit the resource's power from the subject utility's system to the identified point of interconnection with another entity's transmission system.

5. Each subject utility shall specify in its Transmission Ranking Cost Report the expected location of each new substation. To the extent consistent with existing conceptual studies, the utilities shall identify substation locations based on knowledge regarding both currently proposed and potential future renewable projects.

6. For any transmission facilities identified in the conceptual studies relied upon for its Transmission Ranking Cost Report that may be shared by renewable projects but which the subject utility considers to be Direct Assignment Facilities rather than Network Upgrade Facilities, the utility shall specify the location and cost of such facilities and shall explain why it considers the facilities to be Direct Assignment Facilities.

ATTTACHMENT A
Methodology for Development and Consideration of Transmission Costs in Initial Renewable Portfolio Standard Procurement

7. Each subject utility shall file its Transmission Ranking Cost Report in I.00-11-001, with service on all parties, within 14 days of the effective date of the order adopting this methodology. Parties may file initial comments, with service on all parties, within 7 days of the due date of the Transmission Ranking Cost Reports, and reply comments within 7 days thereafter.

8. Utility cost estimates in the Transmission Ranking Cost Reports shall be for the sole purpose of ranking resource bids in the RPS selection process. The Transmission Ranking Cost Reports do not constitute either System Impact Studies or Facilities Studies under the ISO electric tariff on file with the Federal Energy Regulatory Commission.

Information to be Included in Bid Submittals for Transmission Cost Ranking Purposes

1. A renewable developer responding to a procurement solicitation shall include at least the following information in its bid:

   a. The expected electric generation output of the facility, or additional output of an expanded facility,

   b. Number and size of individual generators,

   c. The expected first point of interconnection with the purchasing utility's transmission grid, as identified in the utility's Transmission Ranking Cost Report,

   d. The date of expected operation,

   e. Type of technology,

   f. Whether the facility is currently interconnected to the transmission grid, and

   g. The status of any interconnection application submitted to the ISO.

ATTTACHMENT A
Methodology for Development and Consideration of Transmission Costs in Initial Renewable Portfolio Standard Procurement

2. A renewable bidder that has applied for interconnection pursuant to the ISO tariff and has obtained a completed System Impact Study and/or a completed Facilities Study shall submit those studies as part of its bid.

3. If the first point of interconnection to the transmission grid is or will be at a transmission facility owned by an entity other than the purchasing utility issuing the procurement solicitation, the bidder shall do the following:

a. For transmission of power on the network of another utility filing a Transmission Ranking Cost Report, the developer shall obtain the relevant transmission cost estimates from that company's Transmission Ranking Cost Report and shall separately state that cost estimate in its bid documentation.

b. If power will be transmitted across the network of an entity not in the ISO control area, the bidder shall separately state its expected costs of obtaining such transmission service in its bid documentation and shall incorporate these costs in its bid price.

Consideration of Network Transmission Costs in Ranking Bids

1. The second ranking of RPS bids to determine the combination of RPS projects that best meets least-cost, best-fit criteria shall entail an iterative process. Each subject utility shall undertake the least-cost ranking of bids, subject to best-fit considerations, to minimize total costs of power from RPS projects, including the cost of needed transmission upgrades.

2. Before undertaking the second ranking of RPS bids, each subject utility shall adjust its transmission cost estimates for each level of transmission specified in its Transmission Ranking Cost Report, if needed, to take into account any generation projects that have been added to or deleted from the ISO

ATTTACHMENT A
Methodology for Development and Consideration of Transmission Costs in Initial Renewable Portfolio Standard Procurement

interconnection queue, any System Impact or Facilities Studies submitted with bids, or any other change to the transmission system not anticipated at the time the Transmission Ranking Cost Report was prepared. The subject utility shall document these changes in its advice letter submitting proposed RPS contracts to the Commission.

3. If a renewable bidder has established a position in the ISO interconnection queue and has submitted a System Impact Study and/or a Facilities Study as part of its bid, the subject utility shall use the cost estimates for network upgrades contained therein in ranking the bids, subject to the following:

a. Unless the project has proposed and the subject utility agrees to accept curtailment in lieu of full deliverability of project output, the subject utility shall adjust System Impact Study and Facilities Study results if needed to reflect deliverability costs. These adjustments shall be transparent and justifiable to the Commission when it reviews proposed RPS contracts.

b. If the System Impact Study and Facilities Study show no network upgrade costs for such renewable bidder and if no adjustments are made pursuant to subsection (a), the soliciting utility shall assume in ranking the bids that interconnection of such renewable bidder shall not result in any network upgrade costs.

c. To reduce the risk of renewable bidders applying to the ISO for interconnection for the sole purpose of reducing the potential network upgrade costs attributable to them in the ranking process and then withdrawing their application if they do not prevail in the bidding process, a renewable bidder that submitted an interconnection application after release of the Transmission Ranking Cost Report shall not be entitled to the assumption in the preceding subsection.

ATTTACHMENT A
Methodology for Development and Consideration of Transmission Costs in Initial Renewable Portfolio Standard Procurement

4. The purchasing utility shall assign its network upgrade costs to specific renewable bidders based on assigning the lowest cost transmission available in each cluster according to the following priority:

a. Renewable bidders that have completed an interconnection application and have obtained System Impact and Facilities Studies before the due date for bids in the RPS solicitation. Such bidders shall be given the network upgrade costs attributable to their position in the ISO interconnection queue subject to limitations and adjustments pursuant to Section E.3 above. In the ranking process, pro rata costs of excess capacity created by network upgrades attributable to such bidders shall be assigned to other projects if it is the lowest cost capacity available to such projects.

b. Other renewable bidders based on their first ranking without consideration of the purchasing utility's network upgrade transmission costs. For an out-of-area bidder, wheeling costs or other transmission costs to the point of interconnection to the ISO-controlled grid are a direct cost and shall be included in the first ranking for comparison to the Market Price Referent. Estimated transmission upgrade costs on another utility's network within the ISO-controlled grid shall be added to the first ranking cost to determine the priority of that bidder for assignment of the purchasing utility's network upgrade costs.

5. The appropriate form of the transmission cost estimate used in assessing a bid, e.g., total cost, per-megawatt (MW) cost, or per-kilowatt-hour cost, may depend on the form of the bid. Each subject utility shall structure and apply transmission cost estimates in a manner that is consistent and transparent to the Commission when it reviews proposed RPS contracts.

6. In their bids, renewable bidders may describe expected network benefits, the extent to which the project would be able to produce Volt

ATTTACHMENT A
Methodology for Development and Consideration of Transmission Costs in Initial Renewable Portfolio Standard Procurement

Amperes Reactive (VARs), and other transmission-related factors, and may propose less-than-full deliverability of product output. Each subject utility shall evaluate proposed network benefits and also curtailability proposals that have been examined through System Impact Studies or Feasibility Studies. It shall utilize consistent, logical approaches to assessing these potential benefits, and its evaluation process should be transparent to the utility's Procurement Review Group and to the Commission.

7. As a simple illustration of the iterative process for the second ranking of RPS bids, consider a cluster where the subject utility has determined that no network upgrade appears necessary for the first 50 MW of new renewable generation added to the grid at that location. Above 50 MW, the next level of network upgrade would provide 50 MW of capacity and would have capital costs of $100 million. Within this cluster are three bidders, each meeting best-fit criteria, listed by increasing cost without consideration of the subject utility's transmission network upgrade costs:

(1) 30 MW bid,

(2) 25 MW bid, and

(3) 20 MW bid in the ISO interconnection queue and with System Impact and Facilities Studies completed before the Transmission Ranking Cost Report was filed (with no adjustments needed pursuant to Section E.3), indicating no network upgrade costs.

ATTTACHMENT A
Methodology for Development and Consideration of Transmission Costs in Initial Renewable Portfolio Standard Procurement

Under this scenario, bidder (3) by virtue of its ISO priority and bidder (1) because of its cost being lower than bidder (2) each would receive a transmission ranking cost of $0. Bidder (2) would receive a transmission ranking cost of $4,000,000/MW, based on the fact that it is estimated to cost $100 million in network upgrades to accommodate its 25 MW of added generation.

ATTTACHMENT A
Methodology for Development and Consideration of Transmission Costs in Initial Renewable Portfolio Standard Procurement

Based upon the least-cost principle, the utility would then iteratively look at the best combination of bids in all clusters, taking into account the transmission ranking costs, to meet the desired amount of renewable procurement. The final result would be the selection of the set of renewable resources that best meets the approved procurement needs at the least cost.

8. As another illustration, assume there are only two clusters, Clusters A and B, with three bidders meeting best-fit criteria in each cluster. The subject utility has determined that there is 50 MW of available transmission capacity for Cluster A and none for Cluster B. The most cost-effective network upgrade to accommodate added generation from Cluster A costs $90 million and will add 100 MW of capacity. The most cost-effective network upgrade to accommodate added generation from Cluster B costs $10 million and adds 25 MW in capacity; the next 80 MW in capacity costs $150 million.

Based on increasing cost (without transmission ranking costs), the bids are ranked as follows:

Bidder A1 — 50 MW bid,
Bidder A2 — 25 MW bid,
Bidder B1 — 25 MW bid,
Bidder B2 — 40 MW bid,
Bidder A3 — 50 MW bid, and
Bidder B3 — 10 MW bid.

Assuming that the price differentials without transmission costs are not significant enough to outweigh the transmission costs, the result would depend

ATTTACHMENT A
Methodology for Development and Consideration of Transmission Costs in Initial Renewable Portfolio Standard Procurement

upon the amount of renewable power sought. If only 50 MW is sought, then A1 would be the winning bidder.

If 75 MW is sought, then A1 and B1 likely would be the winning bidders, as B1 has a total transmission upgrade cost of $10 million, unless there is a very significant price differential between B1 and A2.

Suppose, however, that 125 MW is sought by the solicitation. A1 continues to have a zero transmission ranking cost. A2 and A3 together have a total transmission ranking cost of $90 million, since both can be accommodated by the 100 MW upgrade. By contrast, B1, B2, and B3 have a combined transmission ranking cost of $160 million for the two upgrades. Absent other price differentials that tip the balance, the likely winners would be A1, A2, and A3. B1 would not be chosen even though its per-MW transmission costs ($400,000/MW) are lower than the per-MW transmission costs of A2 and A3 combined ($1.2 million/MW).

9. The transmission ranking costs developed according to this methodology shall be used only for the least-cost, best-fit ranking evaluation. Winning renewable bidders must file interconnection applications with the ISO to interconnect their facilities to the transmission grid. Following submission of a completed interconnection application to the ISO, System Impact and Facilities Studies would be performed to assess actual transmission upgrade needs.

ATTTACHMENT A
Methodology for Development and Consideration of Transmission Costs in Initial Renewable Portfolio Standard Procurement

(END OF ATTACHMENT A)